BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING INPUT ON REAL-TIME PRICING DESIGN ISSUES

Background

On March 4, 2004, the Working Group 2 (WG2) moderators forwarded me a report entitled "Key 2-Part RTP Design Issues on Which WG2 Needs Guidance" (Guidance Report). The Guidance Report is attached to this ruling as Attachment 1. By this ruling I seek parties' input to allow the Assigned Commissioner to provide the necessary guidance to allow WG2 to make progress on developing a two-part real-time pricing (RTP) tariff.

Questions for Comment

After reviewing the Guidance Report, I seek input on the following questions:

1. Should the primary objective in designing a two-part RTP tariff be load reductions during periods of high prices or constrained system conditions OR cost based pricing OR some other objective? Why?

2. Should nonbypassable charges (public purpose programs, nuclear decommissioning, competition transition charge) be assessed on incremental usage above a customer baseline load? If the Commission decides that nonbypassable charges should be assessed on incremental usage above a customer baseline load, should an RTP tariff still be developed?

3. Should Department of Water Resources (DWR) costs (energy costs, bond charges, etc.) be assessed on incremental usage above a customer baseline load? If the Commission decides that DWR costs should be assessed on incremental usage above a customer baseline load, should an RTP tariff still be developed?

4. Should any portion of fixed generation costs be recovered as part of the incremental usage price? If so, what portion? If the Commission decides that some portion of fixed generation costs should be recovered as part of the incremental usage price, should an RTP tariff still be developed?

5. Are there legal, statutory, or other requirements that require the costs addressed in the prior three questions to be assessed on incremental usage above a customer baseline load? Explain.

6. Should transmission and distribution charges be assessed on all load or just the customer baseline load? Why?

7. Given the primary objective you support in response to Question 1, should the RTP tariff be mandatory or voluntary to best accomplish that objective? Why?

8. Is additional briefing or comment (beyond the opportunity afforded by this ruling) necessary for the Assigned Commissioner to provide the guidance requested? Are there factual matters in dispute for which evidentiary hearings are necessary in order to provide the guidance requested?

Therefore, **IT IS RULED** that:

1. Respondents shall, and other parties may, file opening comments on the questions set forth above no later than March 30, 2004. Reply comments may be filed by April 9, 2004.

2. Electronic service shall be performed as described in my February 9, 2004 ruling.

Dated March 15, 2004, at San Francisco, California.

/s/ MICHELLE COOKE

Michelle Cooke
Administrative Law Judge

ATTACHMENT 1

Workshop Report
Key 2-Part RTP Design Issues on Which WG2 Needs Guidance

Mike Jaske, CEC and Bruce Kaneshiro, CPUC
March 2, 2004

I. Purpose and Background

a. Purpose

D.03-06-032 as well as the November 24 Assigned Commissioner Ruling (ACR) in Phase 2 of R.02-06-001 require Working Group 2 (WG2) to develop a proposed 2-part real time price (2-part RTP) tariff and supporting implementation package. This workshop report summarizes issues crucial to the development of a 2-part RTP tariff that WG2 has been unable to resolve within itself. WG2 seeks clarification on several ratemaking issues from the Assigned Commissioner. WG2 requests that the Assigned Commissioner identify an appropriate process resulting in guidance that will enable WG2 to proceed with its development of an RTP tariff and customer support program.

b. Background

Classical 2-part RTP tariffs as exemplified by those of Georgia Power (GP) recover virtually all utility costs through a fixed, unchanging customer baseline load (CBL) priced using the rates of the otherwise applicable tariff. This is the “first part” of the 2-part RTP tariff. The second part is the charge computed by deviations of actual usage from the CBL priced at the marginal price. Generally the marginal price consists of market price and a small number of other variable costs. If actual usage exactly matches the CBL then the charges are entirely from the first part and the second part of the bill is zero.

After brief initial discussions immediately following the experiential workshops of September 2002, WG2 deferred development of a 2-part RTP tariff in hopes that other forms of dynamic tariffs might be developed more easily and implemented more quickly. WG2 prepared and submitted several working group reports which ultimately led to the adoption of three tariffs and programs in D.03-06-032. In Phase 2 of R.02-06-001, WG2 was directed by a November 24, 2003 ACR to focus on development of a complete 2-part RTP tariff package, with a pilot being a possible intermediate effort to refine the RTP tariff itself.

WG2 has interpreted this direction to require the development of a Day Ahead form of 2-part RTP tariff. Among the several forms of RTP tariff that exist, a Day Ahead form requires that hourly prices be made available at some point on the Day Ahead of the day in which energy consumption takes place. This Day Ahead notification of hourly price patterns facilitates participants to schedule load changes in ways that could not be possible if prices were revealed after the fact or even a couple of hours in advance. Hour Ahead or near-real time versions of a 2-part RTP tariff are feasible, but they seem less likely to appeal to a broad set of potential participants; therefore, WG2 has assumed that they come later once some degree of satisfaction with an initial Day Ahead tariff has emerged.

WG2 has held meetings to discuss 2-part RTP tariffs on September 23, October 28, November 17, December 11, 2003 and January 22, 2004. Despite this effort, WG2 cannot itself resolve certain specific design issues. Thus, WG2 seeks *ex ante* clarification of these specific issues to allow it to more efficiently develop the requested 2-part RTP tariff package. An *ex post* resolution of these issues during the Commission's review of a full 2-part RTP tariff package risks much wasted effort if the Commission were unwilling to endorse the proposed 2-part RTP tariff due to fundamental rate design issues. In addition, WG2 participants will be able to make very little progress until there is at least partial resolution of these issues.

The results of this clarification will have significant impacts on the viability of the tariff.

II. Objectives for a 2-Part RTP Tariff and Tradeoff Among Conflicting Objectives

a. Objectives

The objectives for a two-part RTP ultimately drive its design. Speaking broadly, there are two alternative objectives:

1. Create additional demand response focusing on load reductions when prices are high or system conditions are tight:
    - Create a tariff with impacts similar to another peak load reduction program to ameliorate tight supply-demand conditions;
    - Provide customers with a cost-saving opportunity to reduce peak load and/or shift load to off-peak, less-expensive periods; and
    - Provide utilities with a way to reduce load at expected peak and reduce costs of compliance with resource adequacy forward commitment requirements established by D.04-01-050;
2. Increase economic efficiency by correctly pricing energy to end-users:
    - Improve economic efficiency through the use of market-based (which should reflect costs in a well-functioning market) price signals irrespective of whether this increases or decreases overall electricity usage;
    - Reduce market prices, as classical economics suggests, by decreasing the slope of the demand curve, e.g. making demand more elastic; and
    - Stimulate industrial activity by pricing increased usage relative to a baseline at marginal costs in periods when market prices are low, because available generating capacity exceeds normal demand;

In addition, the following legal and policy constraints apply:

1. Coordinate development of and expectations for an RTP tariff with overall market design;
2. Continue to collect expected levels of funding for public purpose programs and other dedicated uses funded by non-bypassable surcharges;
3. Satisfy utility and/or DWR revenue requirements; and
4. Comply with any legal requirements.

b. Resolving Tradeoffs Among Objectives

Both of the two major objectives have some degree of support. Unfortunately, these objectives conflict with one another or the constraints to some extent, so they cannot be fully achieved. The following brief observations provide a sense of the conflicts that appear to exist among the objectives or sub-objectives. WG 2 seeks further guidance about these conflicts. In particular, a prioritization of the objectives would be helpful in understanding what the Assigned Commissioner hopes to accomplish with RTP, which WG2 can use to develop the RTP tariff design and/or its implementation support from utilities.

For example, if the goal of the tariff is to encourage demand reduction just at the time when the system's supply/demand balance is tightest, then the marginal prices should be based on uncapped market prices. If market prices are capped, as is currently the case, and thus may not by themselves provide enough stimulus to achieve significant response from participants, then a reliability adder should be considered. Such an adder would provide an additional incentive to encourage participants to respond when for policy reasons market price caps cannot be avoided.

The classical 2-part RTP tariff raises concerns among utilities about revenue recovery for transmission and distribution allocated to classes eligible for an RTP tariff. As one option for resolving these concerns, the Georgia PUC allows GP to recover some distribution costs from individual customers through customer-specific charges who significantly increase their usage above CBL values. In addition, estimated variable costs of transmission are included within the marginal price and participants contribute to these costs through the second part, while embedded transmission costs are recovered with the CBL in the first part.

If RTP customers must pay for DWR costs and other nonbypassable charges for incremental usage, and, more so, if they must pay a pro rata share of fixed generation costs even for this incremental usage, the RTP tariff may provide little potential benefit or savings. In the judgment of most WG2 members, inclusion of such charges would so diminish interest that little participation should be expected.

How would the development of an RTP tariff affect utility actions pursuant to the procurement decisions? In D.04-01-050, utilities are required to procure 90% of their peak demand and planning reserve requirements one year in advance. Would these needs include the peak demand of RTP customers before their response to high market prices or just the portion estimated to remain after the response? Can an RTP tariff allow utilities to reduce compliance costs? If such cost reductions are achieved, would they be allocated to those customers on an RTP tariff or shared with non-participants?

III. Marginal Price for Incremental Changes in Usage

A classical 2-part RTP tariff uses a market-based price as the marginal price signal to value departures from the CBL. If departures are positive, then the customer pays an increment times the marginal price. If the customer reduces load compared to the CBL the customer receives a credit for the decrement times the market price.

a. Elements of the Marginal Price

There are numerous sources of cost that might be included along with direct market-based prices themselves to compose the actual hourly marginal price. To the extent that costs are variable, then some consideration of them is legitimate. However, at least some aspects of generation costs are fixed and not variable. WG2 requests clarification of the extent to which these fixed costs must be included within the marginal price.[1] Questions include:

- Should DWR bond charges be applied to all load or just to the rates charged for CBL usage patterns?
- Should the DWR power charges be added to the RTP market price?
- Should incremental or decremental usage around the CBL include a CTC component?
- Should the marginal RTP price include fixed generation costs for URG and/or DWR?

Are there legal or other requirements which necessitate recovery of such costs from the incremental usage of an RTP customer? In particular, do the sections of the Water Code created by AB1x necessitate imposition of DWR costs on a per kWh basis on all usage? Given the interactions between the Commission and DWR on DWR revenue requirements, is this an issue to which DWR must give its consent, or may the Commission resolve this issue itself?

b. Sources of a Marginal Price

As noted above, the particular version of RTP tariff under development is a Day Ahead 2-part RTP tariff. As such, it requires Day Ahead values for hourly marginal prices. One presumes that the marginal prices are largely determined by organized markets in which the price is a result of bids to buy and offers to sell energy in a specific hour. Customer representatives have expressed strong preference for reliance upon transparent, market-based prices.

The now-defunct California Power Exchange (CalPX) operated a market from 1998 to early 2001 in which such prices were readily usable for the proposed form of RTP tariff. In lieu of the CalPX, what is an acceptable source of market-based price? Clearly the forthcoming ISO Day Ahead hourly price is the best basis for a Day Ahead version of 2-part RTP tariff, but the ISO has deferred implemented of this group of MD02 market changes until Fall 2005. Should an RTP tariff be developed using a synthetic price series?

If an appropriate synthetic price is acceptable until the CAISO has a transparent short-term forward price, what proxy would be acceptable for such a price? CAISO INC and DEC balancing prices are only available on an *ex post* basis, so a customer cannot use these to make

[1] Existing tariffs almost never distinguish between fixed and variable costs. Ratemaking for larger customers in California generally charges the first kWh and the last kWh in any billing period the same price.

purchase decisions.[2] Are forecasts of *ex post* prices based on actual historic prices and factors like system load or estimated level of reserves acceptable as sources for synthetic prices? Is it permissible to combine true forward prices from markets like the Intercontinental Exchange, which are only available as off- and on-peak values, with day-ahead ISO-forecasted load shape data to create some hourly variation in prices as one expects from an hourly energy market? Utility system lambdas used to be a source for synthetic hourly costs, but utilities no longer compute these estimates of hourly system costs.

IV. Recovery of Authorized T&D Revenue Requirements and Non-Bypassable Surcharges

There may be tradeoffs between RTP tariff design and stability/level of funding to recover specific categories of costs.

The classical 2-part RTP tariff can operate as a rider on an Otherwise Applicable Tariff (OAT) by using a customer baseline load (CBL) as the billing determinants for the OAT in each billing period. Rather than actual usage, the CBL usage pattern is charged using the OAT's rates to determine the customer's bill. In this approach, if there are significant expansions of energy consumption that the RTP participant would have implemented anyway, then the utility may not collect as much T&D or non-bypassable surcharge revenues as they would have if the customer had stayed on the otherwise applicable tariff. If the increase in consumption resulted from low marginal prices alone, then the RTP participant has provided the necessary variables costs and the embedded costs have been recovered through the CBL. Of course, to the extent an RTP tariff participant simply responds to high prices by reducing on-peak consumption, this could increase T&D and non-bypassable surcharge revenues compared to those under the OAT, since the customer would be paying for the full CBL load instead of the lower actual load and if the RTP response avoided setting a maximum demand that was still present in the CBL pattern.[3]

An alternative approach is to develop a "multi-part RTP tariff" in which several charges continue to be computed using contemporaneous billing determinants, e.g. standard billing determinants of the OAT computed from the measurements of customer load in each billing period. This form of RTP tariff means that the scope of charges determined by the CBL shrinks to that of generation. Although transmission and distribution are the prime examples of what could be charged either by a CBL or contemporaneous billing determinants, California has a

[2] D04-01-013 adopts use of ISO INC prices for the short term "safe harbor" pricing for usage of a direct access customer temporarily served by the IOU. D04-01-013 is precedential in that it explicitly directs conversion to a forthcoming ISO replacement price series upon its availability. Unfortunately, both of these price series are historic, not forward prices, and thus do not directly satisfy the needs for the particular form of 2-part RTP tariff directed by the 11/24/2003 ACR.

[3] These nuances of T&D revenue impacts are strongly inter-related to the way in which the CBL is established.

unique reliance upon non-bypassable surcharges to fund public policy programs and nuclear decommissioning costs.

WG2's issue is whether non-generation charges (e.g. transmission and distribution (T&D)) and non-bypassable charges (e.g. public policy programs (PPP), and nuclear decommissioning costs (ND)) should be applied to all load (taking into account any incremental or decremental deviations from a customer baseline (CBL)) or just to the CBL? If surcharged costs are assigned to the CBL, then revenues would continue to be stable. If surcharge costs are assigned to the incremental or decremental usage, then what is collected may be more volatile. To the extent that a CBL is an accurate reflection of what usage would be absent either high prices or low prices, then surcharge revenues collected would be similar to current expectations. When RTP prices are high or low, then changes in usage could affect surcharge revenues. Whether this surcharge revenues impact is positive or negative is unknown.

a. Loss of T&D Revenue Additions from Major Expansion in Energy Usage

If T&D revenues are collected by the application of the OAT T&D rates to the CBL, then if aggregate consumption expands substantially, the utility will collect less T&D revenue that it would have collected were the participant to have simply stayed on the OAT (assuming one can distinguish between those RTP participants that would have expanded anyway and those that expanded only because of the low marginal prices). Unless the GP method of splitting T&D revenue recovery between fixed and variable costs is adopted, utilities have expressed two concerns: (1) reduction in additional T&D revenues, and (2) inability to recover increased T&D costs associated with customer-specific usage increases. If the CBL remains fixed for a multi-year period, then these concerns are magnified.

Regarding the first of these concerns, expanded usage is most likely to occur in off-peak hours when T&D demand charges are low or zero. Thus if major usage increases are concentrated in off-peak hours, then foregone revenue increases may not actually be substantial.

Second, RTP tariff special conditions could be designed that require customers to pay attributable costs outside of tariff rates if a major expansion of usage creates actual costs.[4]

These effects should not be long lasting since a proper cost of service study distinguishing between OAT and RTP tariff customers should be able to identify true cost of service basis for charges T&D charges, and this would provide the basis for revised rates.

b. Changes in T&D Charges Resulting from Load Shifts

If T&D charges applied to all load, then an RTP tariff participant would be charged for T&D just as they are today. This means that incremental load (usage beyond the CBL) would be charged for these cost categories at tariff rates and decremental load (usage short of the CBL)

[4] Such costs are currently identified and recovered from GP RTP participants.

would not pay these costs. The implications of continuing to charge all load for T&D is different when the customer usage is an increment over the CBL versus a decrement under the CBL. However, an important issue for T&D is that rates differ between TOU periods, since shifts of load from one period to another can have financial impacts for the ISO even if the total energy used by the customer is the same. This makes the T&D charge issue different from the PPP/ND issue discussed below.

Demand charges, which recover most T&D costs, are based on the highest usage in a 15-minute period during the billing month. Some of these charges are based on the highest usage in a given TOU period and some on the maximum demand regardless of when it takes place. If a customer were to shift its entire load from on-peak to off-peak during a billing month, it would no longer pay the on-peak demand charge. There is no off-peak TOU demand charge, so that revenue would be lost to the utility. If the customer shifted half of its demand to another, lower-demand-charge time period (so, for example, the maximum demand were 500 kW instead of 1 MW) its payment for that demand charge would be half as large. Of course, this would only result from a shift of all the usage during that billing period, or a reduction in the *maximum* usage for that billing period. If a customer used power at its usual maximum demand except during a period of very high energy prices lasting less than a billing period, its payment of the demand charge wouldn't change at all.

When the customer is in an increment situation for a given hour, this will generally mean that RTP prices are low for that hour and the customer finds value in using more electricity in this hour than would otherwise have been the case on the OAT. In some instances this may mean some load has been shifted from one hour to another. Load shifts have an implication for T&D revenues charged since shifts of load from peak to shoulder peak would raise less revenue for the utility.[5] In other instances (not mutually exclusive from a load shift) an RTP participant might choose to increase usage in low priced periods. In these instances, odds are that such prices occur in shoulder and off-peak periods, so additional T&D revenues from the OAT from such incremental usage would be much smaller since demand charges are much lower in shoulder- and off-peak periods. A sophisticated analysis of load patterns and hypothetical adjustments to RTP prices would be needed to understand how to predict net changes in T&D revenues.

When the customer is in a decrement situation, charging T&D on a contemporaneous basis will potentially reduce T&D revenues if the monthly maximum load for either the peak- or shoulder-peak periods are affected by the decrement. Whether this happens requires more experience with actual or reasonable forecasts of RTP price patterns to see what is most likely. However, one could speculate that the conditions leading to high hourly system RTP prices (motivating a decrement) might be coincident with the conditions causing the RTP participant's maximum load, thus the utility might be in a position to lose some T&D revenue.

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[5] For example, in the 1/22/2004 version of SCE's TOU-8 rate, a customer pays $13.29 per kW in the peak period but only $4.71 per kW in the shoulder peak period and nothing in the off-peak period.

c. PPP/ND Charges

Since PPP and ND charges are based on a uniform energy charge in $/kWh for all usage, the specific hours in which energy is used is not important. All that matters is total energy consumed.

If total energy is increased as a result of participation on an 2-part RTP tariff, presumably because there are enough low-priced hours that the customer has expanded activities or improved comfort levels, then using contemporaneous billing determinants will collect more money. Assigning these charge categories to a fixed CBL would not increase revenues when incremental consumer occurs.

If total energy is decreased, presumably because the hypothetical RTP customer reduced load at some hours and did not make it up in other hours, then using contemporaneous billing determinants will reduce PPP/ND revenue collected. Assigning these charge categories to a CBL would not result in revenue reductions.

Looked at from the participant's perspective, charging PPP/ND on a contemporaneous billing determinant basis reduces the participant's incentive to increase load when market prices are low, since actual cost per kWh charged for this incremental consumption is higher than the pure market price. Charging PPP/ND using a fixed CBL increases the participant's incentive to increment load over and above the CBL when market prices are low, since PPP/ND charges are not incurred for this incremental usage. Thus, it would appear that assigning PPP and ND to contemporaneous billing determinants discourages participation in RTP tariffs by increasing marginal prices over what they might be, and increases volatility in revenues collected for these purposes.

The feasibility of assigning PPP and ND surcharges to a fixed CBL rather than contemporaneous billing determinants may be governed by interpretations of the statutes creating these non-bypassable surcharges.

V. Revenue Recovery from Various Customer Classes

Creating 2-part RTP as a rider on one or more existing tariffs could result in aggregate departures in overall revenue requirements compared to those used to develop the rates for the OAT. If the costs of generation scale similar to those for the revenue collected, then the utility may not need to recover these differentials in revenues versus revenue requirements. However, depending upon the rate design, there could be components of costs intended to be recovered through demand and energy charges that impose net revenue shortfalls on the utility.

How will the variation between the RTP rate revenue and the OAT be addressed? If the aggregate RTP price falls below the average price for the OAT (otherwise applicable tariff), will this be considered an undercollection, and, if so, how would it be recovered? Also, if they fall above, how is the overcollection spread? This issue is more likely to arise if the RTP is a rider to an OAT than a separate schedule.

Is participation on RTP tariffs expected to be large enough that these revenue recovery issues are important enough in the initial year or two? Is it reasonable to wait to see if there is a significant problem before devising solutions and advocating one or another? If this topic is deferred, can simple methods be developed and implemented to provide a reasonable estimate of the revenue impacts? If these problems are suspected, should specific cost of service studies be conducted to discern actual costs of service for subclasses of customers and these used to revised rates?

VI. Coordination of an RTP Tariff with Overall Market Design

The degree to which an RTP tariff with substantial participation and effective implementation is compatible with overall market design has been questioned by some WG2 participants. Two alternative views of market design seem to be prevalent. One has a much greater "fit" with RTP tariff response than the other.

An **excess capacity** market is designed so that there is always a large excess of supply over demand so that spot market prices do not rise very much when peak loads are extreme. Some policy makers want this form of market design so that the explosion of prices in the CalPX and CAISO markets in 2000-2001 is never repeated again. Resource adequacy requirements sketched in D.04-01-050 could be implemented in a way to create a high level of reserves and tight "resource counting conventions" which would ensure that there are additional resources that could not qualify leaving no outlet except the spot market. Such an excess of capacity would lead to spot market prices close to costs even in relatively tight market conditions. This design would appear to minimize spot market prices (in terms of prices exceeding costs) as well as to minimize spot market price volatility.

A **balanced resources** market is designed with less reserve margin than in the **excess capacity** market, and supply/demand conditions become tighter when peak loads are extreme. Spot market prices tend to rise more in tight supply/demand conditions simply due to greater reliance upon expensive resources and scarcity rents. Rather than accept such prices, some end-users would choose to be on RTP tariffs and voluntarily reduce loads when prices are high, reducing their overall electricity bills. Annual average retail prices are probably lower in this market design, since these prices do not have to reflect as much generation investment. The load reductions from RTP tariff participants are an important contribution to this market design since they reduce total system peak, which reduces spot market prices at the point they would otherwise be the highest. Thus, RTP tariff induced load reductions provide a benefit to all customers served either in whole or in part out of the spot market.

An RTP tariff whose design emphasizes reduction of peak demand may not be useful or especially effective in the first of these market designs. If market prices are rarely high because of excess capacity then there would be no need to attract participants to an RTP tariff through additional incentives. An RTP tariff that simply passes market prices along to participants may be the appropriate design for an excess capacity market. However, interest in and load modifications stemming from participation might be minimal since prices do not vary enough to really stimulate participation. An RTP tariff designed to reduce peak demand may be highly useful in the second of these market designs. In fact developing and maintaining RTP response may be so crucial to the overall success of this version of market design that end-users are provided additional incentives to get onto and perform under such RTP tariffs.[6]

VII. Resolution of the Issues

a. Restatement of the Issues

1. Should an RTP tariff be considered as a load reduction program to clip peak, or as a means to communicate the proper pricing signal to participants irrespective of whether they increase or decrease loads?

2. Should marginal price include any fixed cost components or should these be recovered using the CBL level of usage allowing the marginal price to be dominated by spot market prices?

3. Should non-generation revenues (T&D costs and various non-bypassable charges) be recovered using CBL usage rather than actual usage?

4. What is the role that RTP tariff impacts play in overall market design?

b. Processes that Could Be Followed to Provide Guidance

There are at least two options WG2 has identified by which issues the Assigned Commissioner agrees to address can be resolved.

First, an ACR can direct parties to file comments on those issues for which it is agreed that guidance can be provided. This may be all or a subset of the general question about prioritizing the objectives and the specific three topics raised herein. These comments, and any reply comments, may provide sufficient information for the Assigned Commissioner to issue a ruling providing the direction WG2 requests. WG2 will then proceed to develop a complete 2-part RTP tariff package and submit this via a WG2 report to the Commission for a decision.

Second, an ACR can direct parties to file comments and also allow parties to propose legal briefs or hearings for specific topics they believe require such procedures. Such comments and reply comments would provide the Assigned Commissioner with sufficient information that an ACR or ALJ ruling can direct parties appropriately. Once legal briefs are filed or evidentiary hearings are completed, then a proposed decision would be issued for comments and ultimate Commission adoption. Once adopted, WG2 would proceed to develop a 2-part RTP tariff following this guidance, and the ultimate 2-part RTP tariff package might be approved on a more

[6] Of course, in the event that incentives are offered to induce performance, participants may be subjected to minimum performance obligations and exit from the tariff could be restricted to ensure that response takes place as expected.

expeditious basis considering it was being submitted pursuant to a Commission decision that had already resolved policy issues.

WG2 acknowledges that some issues for which we are requesting guidance may not be resolved on this *ex ante* basis. Such issues may result in less support for the WG2 2-part RTP tariff package and the possibility of having a more formal record established (evidentiary hearings or legal briefs) in order to adopt the tariff.

(END OF ATTACHMENT 1)

CERTIFICATE OF SERVICE

I certify that I have this day, served electronically the parties who have provided e-mail addresses, and served by U.S. mail the parties who do not have e-mail addresses, a true copy of the original attached Administrative Law Judge's Ruling Seeking Input on Real-Time Pricing Design Issues on all parties of record in this proceeding or their attorneys of record.

Dated March 15, 2004, at San Francisco, California.

/s/ KE HUANG
Ke Huang

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074, TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.